U.S. NUCLEAR REGULATORY COMMISSION
REGION I

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Licensee:	BEC Energy 800 Boylston Street Boston, Massachusetts 02199
Facility:	Pilgrim Nuclear Power Station
Inspection Period:	April 19, 1999, through June 9, 1999
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EXECUTIVE SUMMARY

Pilgrim Nuclear Power Station
NRC Inspection Report 50-293/99-03

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers resident inspection for the period of April 19, 1999, through June 9, 1999. In addition, it includes the results of Region 1 specialist inspectors; in the Engineering/ISI area during May 24-28, 1999; in the Security area during May 10-12, 1999; an operability evaluations initiative inspection during May 10-14, 1999; a radiological controls outage inspection during the week of May 17, 1999; and a Y2K readiness review on April 19-23 and May 28, 1999.

Operations

- Shift turnover briefings lead by the off going nuclear watch engineer were detailed and included a good discussion on equipment availability and shutdown risk. (Section O2.1)

- Reactor fuel movements were performed in a controlled manner with effective communications between contract fuel handlers, reactor engineers, control room operators and the SRO stationed on the refueling bridge. (Section O2.1)

- Operators stopped fuel movements when necessary to resolve degraded conditions such as poor reactor water quality and also when a source range monitor started to read erratically. This reflected a conservative nuclear safety approach by operations personnel. (Section O2.1)

- A new camera angle during core verification revealed a fuel support piece which was not fully seated. Also, a cap screw was removed from a control rod drive which had jammed the rod during the previous operating cycle. Good FME practices were observed during refueling activities. Refueling activities were conducted in a controlled manner with overall good performance. (Section O2.1)

- Several tagging errors resulted due to license operator errors both while hanging and verifying checking tags. These errors occurred early in RFO12 during the highest demand period for work release indicating that management involvement was lacking in the oversight and scheduling of tagouts. Interim corrective actions were implemented to improve future tagging performance. This severity level IV violation is being treated as a non-cited violation, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PRs 99.9190, 99.1121, 99.9264 and 99.9914. (NCV 50-293/99-03-01) (Section O4.1)

- Training provided to licensed operators on modifications implemented during the cycle 12 refueling outage was determined to be good. Simulator and job performance measures were used, as necessary, to ensure operators could properly operate the equipment and that they understood the modifications. (Section O5.1)

Executive Summary (cont'd)

Maintenance

- The disassembly and reassembly of the reactor vessel was performed well by the refueling crew. Good teamwork was noted between the craft and contract personnel. (Section M1.1)

- Several new initiatives were used during the outage including use of electronic logs which were accessible site wide, new reduced weight heavy-lifting slings, and a relocated outage work control center. (Section M1.1)

- Pre-job briefs for surveillance activities were determined to be good with proper oversight provided by the test engineer and quality assurance personnel. (Section M1.1)

- Post work testing for observed maintenance activities was determined to be good and in accordance with code requirements. (Section M1.1)

- Several procedure usage problems were identified by the licensee and the inspector. One problem dealt with the mispositioning of LPCI throttle valve MO-1001-28B during performance of the EDG load sequence test. This severity level IV violation is being treated as a non-cited violation, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PR 99.1647. (NCV 50-293/99-03-02) (Section M1.1)

- The emergent replacement of the underground SSW discharge piping, replacement of the DC power panels and CRDM drive change-outs were well planned and executed. (Section M1.1 and M1.2)

- Deferred work items were properly tracked and dispositioned by the outage review board. No work items were removed from the outage scope that would adversely affect safe plant operations. (Section M2.1)

- BEC Energy was implementing inservice inspection activities in accordance with their ISI program. NDE personnel were qualified, and adhered to procedures while performing examinations. Deficiencies identified during inspection activities were properly documented. HPCI system weld drawings accurately reflected the location of welds in the plant. (Section M3.1)

- The failure to establish specific procedural guidance and human performance errors contributed to the cause of the transformer fire. (Section M3.2)

Engineering

- No safety concerns were noted concerning the open operability evaluations reviewed. (Section E2.1)

- Two minor problems were noted during the review of operability evaluation (OE) 98-052, "Excessive Head Loss in Reactor Building Closed Cooling Water Pump Startup Strainers." These included attention-to-detail problems pertaining to the procedures governing operability and engineering evaluations. Also, the preliminary engineering work supporting PDC 99-09, "Decrease of the EDG Building Low Temperature Design Limit," was not comprehensive. Structural considerations were not being reviewed regarding the 20°F EDG room design temperature decrease and the resultant impact on the piping stress analysis, the EDG silencer supports, and the compressed air receivers. (Section E2.1)

- The licensee has a process in place to control the OE backlog and appears to be on track in reducing the number of open OEs, expecting to have 5-10 open OEs at the end of RFO 12. (Section E2.1)

- The licensee identified several instances of noncompliance with technical specifications and design requirements. These issues were properly captured into the licensee's corrective action program and reported as LERs. Effective corrective action was taken to resolve these issues. These issues are being treated as Non-Cited Violations (NCVs) consistent with Appendix C of the NRC Enforcement Policy. The NCVs involved: (1) the failure to have sufficient diesel fuel oil supply on-site, (2) inoperable reactor building closed cooling water alternative shutdown panel, and (3) inoperable control room high efficiency air filtration system. (Section E8)

<u>Plant Support</u>

- Radiological controls were effectively implemented for RFO12 as evidenced by close health physics oversight of work and improvements in radiological controls implemented for drywell work including assignment of a drywell radiological controls coordinator, installation of permanent shielding, and use of video monitoring. (Section R1)

- An opportunity for improving radiological controls for access to upper drywell elevations during movement of irradiated core components was identified and licensee staff responded quickly to improve program controls. (Section R1)

- The problem reporting system was effectively used to identify, evaluate, and resolve radiological control deficiencies. (Section R7)

- The licensee was conducting security and safeguards activities in a manner that protected health and safety in the area of access authorization and fitness for duty. (Section S1)

- The review of the licensee's audit program for security and safeguards activities indicated that audits were comprehensive in scope and depth, that the audit findings were reported to the appropriate level of management, and that the program was being properly administered. In addition, a review of documentation applicable to the self-assessment program indicated that the program was being effectively implemented to identify and resolve potential weaknesses. (Section S7)

- Response to the main transformer fire by fire brigade members was good; their immediate response prevented any serious damage to the plant. The licensee properly classified the event in accordance with emergency classification guidelines. (Section M3.2)

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ATTACHMENTS

REPORT DETAILS

Summary of Plant Status

At the start this inspection period, the Pilgrim Nuclear Power Station (PNPS) operated at 80% reactor power. On May 7, 1999, operators shutdown and cooled down the reactor to cold shutdown conditions for commencement of RFO12. The outage was scheduled for 30 days; however, due to a problem with the main electrical transformer, the refueling outage was extended to replace the transformer. The reactor remained shutdown at the end of this inspection period.

The licensee declared an Unusual Event on May 18, 1999, due to an electrical fire in the main transformer. Further details of this event are discussed in Section M3.2 of this report.

By letter No. 99-93, dated May 3, 1999, the NRC approved the transfer of the Pilgrim operating license from Boston Edison to Entergy Nuclear. The license transfer is scheduled to occur in July 1999 after completing RFO12.

I. OPERATIONS

O1 Conduct of Operations[1]

O1.1 General Comments (71707)

Operators competently performed a normal shutdown and cool down of the plant to commence RFO12. During the outage, the protected train safety system concept was used. Signs were hung on components in the field to alert personnel not to interfere with protected train equipment. Good coordination was evident when operators placed the fuel pool cooling system into the augmented fuel pool cooling mode. This evolution required extensive coordination from several local stations in the field and in the control room. Lastly, a major safety system loop swap was well planned and completed during the outage.

The inspector attended several shift turnover briefings conducted by the off going nuclear watch engineer (NWE). The briefings were detailed and included the status of equipment availability and also reviewed new problem reports. The outage plan-of-the-day included a listing of protected/available equipment. The plan was updated daily by NWEs.

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[1]Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

O2 Operational Status of Facilities and Equipment

O2.1 Refueling Operations

a. Inspection Scope (71707, 60710)

The inspector observed portions of reactor fuel movements made during two fuel shuffles. Observations were made locally on the refueling floor and remotely in the control room. The inspector also observed other portions of refueling activities from the refueling floor.

b. Observations and Findings

Contract fuel handlers were used under the direct supervision of a licensed BEC Energy senior reactor operator (SRO). The refueling bridge crew consisted of 2 contract fuel handlers, a SRO and a reactor engineer. The inspector observed that fuel bundles were moved in a diligent manner with no mishaps. The fuel movement plan was carefully followed and several independent verifications were made to ensure that the proper fuel bundle was selected and moved to the correct location with proper bundle orientation. Effective communication and teamwork was observed between contract and licensee personnel. Independent reviews of fuel moves were performed by the SRO, reactor engineer and also by the control room operators who were in direct communication with the refueling bridge personnel. No problems were identified by the inspector.

Operators acted conservatively and demonstrated a proper nuclear safety focus by stopping fuel movement when anomalies arose. For example, operators stopped fuel movement when the reactor cavity water clarity degraded to the point where the fuel bundle bail handle serial numbers could not be read. The issue of poor reactor cavity water quality is further discussed in Section R1.1 of this report. Also, fuel movement was stopped when the 905-panel reactor operator in the control room identified that one source range monitor was operating erratically. The licensee revised the fuel transfer plan to allow fuel movement to continue in the unaffected core quadrants per the plant technical specifications. The inspector determined that operators acted promptly to identify and resolve degraded conditions during the fuel handling activities.

Foreign material exclusion (FME) controls were observed to be in effect during refueling operations. A dedicated FME watch was established on the refueling floor with a logbook to account for all tools and materials. The inspector reviewed the log, which was maintained up-to-date and no problems were identified. During in-vessel inspections, some foreign material was found in the annulas region of the vessel. This material was subsequently removed by the refueling crew. The licensee determined that this material had been introduced into the core during a previous refueling outage. Lastly, the inspector confirmed that senior licensee managers periodically toured the refueling floor to provide management oversight of refueling activities.

After fuel movement and core verification activities were completed, the inspector performed an independent verification of the location of 280 fuel bundles. This was done by viewing the core verification videotape and comparing each bundle to the cycle 13 core map to ensure correct location and orientation. Additionally, the inspector confirmed the accuracy of the core map by verifying the map against the Fuel Cycle 13 Management Report prepared by the General Electric Company. The inspector noted that effective communication techniques were used between the reactor engineer and contract fuel handlers during the core verification process. The inspector independently determined that all 280 fuel bundles reviewed were located in the correct core location with the proper orientation.

The licensee used a new camera angle during the core verification to ensure that all fuel bundles were properly seated. During the inspection, the licensee identified that the fuel bundles in cell 26-03 appeared to be 3/4 inch higher than adjacent bundles. The licensee documented this anomaly and initiated corrective actions. The four fuel bundles were removed and the associated fuel support piece repositioned. The four fuel bundles were reloaded but visual inspection revealed that the bundles were still sitting approximately ½ inch higher than adjacent bundles. The licensee contracted the General Electric Company to perform an analysis to accept the condition as-is. The inspector was informed by the reactor engineering supervisor that an engineering evaluation would be completed prior to restart to confirm that this condition was acceptable. The inspector determined that the licensee performed well by using a new camera angle to assure that all fuel bundles were properly seated.

Portions of other refueling work was also observed. The licensee developed a special procedure to evaluate the condition of control rod 02-23 since this rod could not be moved and remained inserted during most of the previous operating cycle. After unloading the fuel bundles surrounding control rod 02-23, the licensee used remote cameras to inspect the control rod drive for any anomalous conditions. The licensee identified a small cap screw which was wedged between the control rod guide and index tubes. The inspector observed the refueling crew retrieve this cap screw using a remote, air-operated pair of pliers. The licensee could not identify the origin of the cap screw. As a precautionary measure, the licensee replaced this control rod drive later in the outage during the control rod drive change-out window.

c. Conclusions

Reactor fuel movements were performed in a controlled manner with effective communications between contract fuel handlers, reactor engineers, control room operators and the SRO stationed on the refueling bridge.

Operators stopped fuel movements when necessary to resolve degraded conditions such as poor reactor water quality and also when a source range monitor started to read erratically. This reflected a conservative nuclear safety approach by operations personnel.

A new camera angle during core verification revealed a fuel support piece which was not fully seated. Also, a cap screw was removed from a control rod drive which had jammed the rod during the previous operating cycle. Good FME practices were observed during refueling activities. Refueling activities were conducted in a controlled manner with overall good performance.

O4 Operator Knowledge and Performance

O4.1 Operations Tagging Problems

a. Inspection Scope (71707,93702)

A review was performed of the problem extent and effectiveness of corrective actions initiated by the licensee to address several tagging errors which occurred during RFO12. In each case, the licensee identified the problem and initiated a problem report to document and evaluate the condition.

b. Observations and Findings

The first tagging event involved a temporary electrical power panel breaker that was to be danger tagged open but was found with the danger tag on the floor and the breaker closed. This problem was discovered by the licensee on May 10, 1999. The licensee initiated PR 99.9190 to document and evaluate this tagging discrepancy and held a critique. The subject temporary power panel breaker was non safety-related and did not feed any loads, so there was no adverse safety consequence. At the end of this inspection period, the licensee's root cause of this event was unknown.

A second tagging event occurred on May 15, 1999, when an operator identified that two feed water system block valves were danger tagged open but the valves were required to be shut. Operations personnel initiated PR 99.1121 to document and evaluate this tagging discrepancy. No adverse safety consequence resulted from this tagging error. The licensee determined that the apparent cause was over-confidence by the operator who hung the tags. Since these valves were non safety-related, no independent verifier was required to verify the implementation of the tagout.

A third tagging event involved several danger tags which were found hung on the incorrect hydraulic control unit (HCU). Tags were found hung on HCU 42-47 vice 42-27. The tags were hung on May 17, 1999. Operations personnel initiated PR 99.9264 to document and review this event. The licensee determined that the apparent cause of this event was misjudgement - spatial mis-orientation by the operators who hung and verified the tags. No adverse safety consequence resulted from this event.

A fourth tagging event occurred on May 27, 1999, when two licensed operators removed the wrong core spray system electrical fuses. Fuse 10A-F2B was removed vice 14A-F2B. This was identified by an electrical lab engineer performing a walkdown of the tagout prior to starting physical work. PR 99.1414 was initiated to document and evaluate this tagging event. No adverse safety consequence resulted from pulling and tagging the wrong fuses. The licensee determined that the preliminary root cause of this event was inattention to detail - unawareness. The operators focused only on the fuse designation F2B rather than the full fuse identification number 14A-F2B.

Collectively, these tagging errors constitute a violation of procedure 1.4.5, "Tagging Procedure." The licensee identified each deficiency and initiated problem reports to document, evaluate and correct each problem through the corrective action process. This severity level IV violation of procedure 1.4.5 is being treated as a Non-Cited Violation , consistent with Appendix C of the NRC Enforcement Policy. This is in the licensee's corrective action program as PRs 99.9190, 99.1121, 99.9264, and 99.9914 **(NCV 50-293/99-03-01)**.

As a result of these tagging errors, operations management stopped all tagging evolutions and convened a standown with all operators. Several interim corrective actions were implemented to improve tagging performance. A pre-evolutionary briefing will be held for every tagout. Tagouts that involve fuses will be completed by having two operators identify and pull the fuses and an independent verification done at a different time. All HCU tagouts will have a peer check so that two operators hang the tags and an independent verification will be done at a later time. Also, at the start of each shift, the operations tagging lead will meet with the operations production manager to discuss significant tagouts to be worked during the shift. Also, operations management will provide 100% oversight during the tagging evolution. The inspector determined that these interim actions were a reasonable effort to improve tagging performance in the short term.

The inspector noted that these tagging errors occurred early during RFO12 when the tagging workload was the highest. Although the operators involved commented that there was no adverse production pressure while establishing the tagouts, on several occasions the flow of work hanging tags was interrupted to support other activities. In one instance, one operator was left to hang over 100 tags by himself on the HCUs. The Operations Manager indicated that one of the tagging problem reports had been upgraded to a significant condition adverse to quality (SCAQ) which required a full root cause evaluation. Further, the manager indicated that the underlying causes would be examined such as better management oversight and application of resources to support tagging evolutions. Lastly, the inspector noted that the Operations Manager had not previously tracked any specific tagging performance indicators such as the number of performance - related tag changes.

c. <u>Conclusions</u>

Several tagging errors resulted due to license operator errors both while hanging and verifying checking tags. These errors occurred early in RFO12 during the highest demand period for work release indicating that more effective shift (i.e., NWE and NOS) and operations department management involvement was needed in the oversight and scheduling of tagouts. Interim corrective actions were implemented to improve future tagging performance.

O5 Operator Training and Qualification

O5.1 Pre-startup Training

a. Inspection Scope (71707)

The inspector attended the plant design change/pre-startup training session held on June 2, 1999. The training focused on modifications implemented during RFO12.

b. Observations and Findings

As part of the licensed operator continuing training program, operations department personnel were trained on modifications implemented during the cycle refueling outage. Training included classroom and simulator training. The training covered 15 objectives including modifications: cycle 13 core design, feedwater regulation valves retrofit and degraded grid voltage protection system.

An instruction module was provided to all attendees. It included a description of the modification, applicable procedures, and drawings. The inspector noted that there was good interaction between the instructor and the licensed operators. As a result of some confusion regarding the modification to the feedwater regulation valve retrofit, the Operations Department Manager required that job performance measure training be included to demonstrate proper operation of how to lock up the valve. The inspector verified that all operations department personnel were scheduled for the training.

c. Conclusions

Training provided to licensed operators on modifications implemented during the cycle 12 refueling outage was determined to be good. Simulator and job performance measures were used, as necessary, to ensure operators could properly operate the equipment and that they understood the modifications.

II. MAINTENANCE

M1 Conduct of Maintenance

M1.1 General Maintenance and Surveillance

a. Inspection Scope (61726)

The inspector observed portions of selected surveillance and maintenance activities to verify use of approved procedures, correct system restoration, and proper post work testing. The following activities were observed:

8.7.1.5 Local Leak Rate Test of Primary Containment Penetrations, Isolation Valves, and Inspection of Containment Structure

8.5.2.7 Hydrodynamic Test for Measuring Leakage Through RHR System, Valve

	MO-1001-68B
8.M.3-1	Special Test for Automatic ECCS Load Sequencing of Diesels and Shutdown Transformer with Simulated Loss of Off-Site Power
E9800005	Replace RHR Valve MO-1001-68B

b. Observations and Findings

The inspector verified that surveillance activities (procedures 8.7.1.5 and 8.5.2.7) appropriately implemented technical specification (TS) surveillance requirements. Good procedure adherence was displayed by the maintenance craft for work activities observed. Test engineers were noted directing surveillance activities with oversight provided by quality assurance department personnel.

Portions of the reactor vessel disassembly and reassembly were observed by the inspector. Overall, the inspector observed excellent performance by the refueling crew which included the use of contractor workers. The reactor vessel stud tensioners worked much more reliably than during RFO10 and RFO11. Some new initiatives worked well including the use of electronic shift logs and kevlar lifting slings for heavy lifts. The new slings were much lighter and easier for the workers to set-up and handle. Also, a new outage control center was established shortly prior to RFO12 in the O&M building adjacent to the control room annex area.

A new effort during RFO12 was to use mixed work teams composed of a plant maintenance worker with a contractor worker. The inspector observed the positive effect of this concept during some electrical breaker maintenance. Work was effectively planned and executed for the DC panel replacement project, the control rod drive mechanism (CRDM) replacement activity and also during motor operated valve testing activities.

The inspector entered the steam tunnel on several occasions and observed maintenance on the 2A main steam isolation valve (MSIV). The inspector observed metal filings in the valve body from the machining work of the seating surfaces. However, a pressure plug was installed in the valve body ports and workers indicated the filings would be removed prior to valve re-assembly. The welders experienced some difficulty in performing weld repairs on the stellite guide ribs but eventually resolved the problem. Lastly, rework was required when a replacement source range monitor (SRM) did not function properly and had to be replaced. This rework resulted in additional radiation dose since the work area was under the reactor vessel in the drywell. The licensee initiated a review to determine why the replacement SRM did not function properly. Preliminarily, the licensee determined that the SRM detector may have been damaged when being transferred to the job site.

During hydrodynamic testing of valve MO-1001-68B, the test pressure could not be achieved due to leakage past the valve. The licensee issued problem report PR 99.9236 to document the problem. Valve MO-1001-68B was cut out and a new valve welded back into the system. The inspector reviewed the post work test for this activity. The licensee tested the valve in accordance with ASME code case N-416-1, "Alternate

Pressure Test Requirement for Welded Repairs or Installation of Replacement items by Welding Class 1, 2 and 3, Section X1, Division 1." The inspector verified that this code case was approved for use at the Pilgrim station and that the valve tested satisfactorily.

The pre-job brief for surveillance 8.M.3-1 was determined to be detailed; test termination criteria, expected plant conditions, abort criteria, and personnel responsibilities were clearly communicated. During review of the initial conditions prior to the performance of the surveillance, the inspector identified that low pressure coolant injection (LPCI) throttle valve MO-1001-28B was not open. The residual heat removal (RHR) system was required to be aligned for LPCI mode (that requires that the LPCI injection valve be open and its breaker closed) per step 3(c) attachment 1 of the procedure. The throttle valve was subsequently opened and the test commenced. Problem report 99.1647 was written to document this condition.

The failure to position valve MO-1001-28B open per step 3(c) of procedure 8.M.3-1 is a violation of technical specification 6.8.A. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PR 99.1647 (**NCV 50-293/99-03-02**).

c. <u>Conclusions</u>

Pre-job briefs for surveillance activities were determined to be good with proper oversight provided by the test engineer and quality assurance personnel.

Post work testing for observed maintenance activities was determined to be good and in accordance with code requirements.

Several procedure usage problems were identified by the licensee and the inspector. One problem dealt with the positioning of LPCI throttle valve MO-1001-28B during performance of the EDG load sequence test.

M1.2 <u>Salt Service Water (SSW) Piping Repair</u>

a. <u>Inspection Scope (61726)</u>

The inspector observed portions of the replacement of the SSW discharge piping and reviewed the circumstances surrounding the damage to two electrical conduits and a potable water line during excavation of the SSW piping.

b. <u>Observations and Findings</u>

The licensee performed an inspection of the SSW system during RFO12 and identified that the discharge piping from the auxiliary bay to the discharge canal was degraded. The degradation was the result of the inner pipe rubber lining becoming loose causing the carbon piping to be exposed to seawater, resulting in significant corrosive wall thinning. The rubber loss extended from the bottom dead center circumferentially up each side about 45 degrees for a length of about 50 feet. Problem report (PR) 99.9207 was written to document this condition.

The licensee performed an engineering evaluation and concluded that the piping was structurally adequate to maintain its integrity under combined pipe weight plus soil loading. The licensee concluded that the SSW discharge piping was operable for decay heat removal and refueling operations. To facilitate the replacement of the SSW piping, the licensee performed a temporary modification and installed temporary SSW piping to allow repair of the buried piping.

The inspector reviewed the licensee's engineering evaluation and concluded that it was technically adequate and identified no discrepancies. A review of the installation of the temporary SSW piping and the subsequent testing revealed that it was properly implemented.

During excavation of the SSW piping, two electrical conduits and a three inch potable water line that supply the shore front were damaged. A review of the circumstances leading to the event revealed that the licensee's site drawing for this location had insufficient detail nor was it drawn to scale. The site characterization map failed to show the water line or the conduits traversing the excavation site. The licensee had performed ground penetration radar of the area and identified an indication traversing the excavation area and modified the site drawing. However, when the licensee overlayed the radar map on the site map they did not have exact reference points resulting in the drawing being slightly offset. The licensee modified the site drawing and excavated the SSW piping with no further problems. The inspector considered the licensee's corrective action adequate to address this issue.

c. Conclusions

The emergent replacement of the underground SSW discharge piping was well planned and executed.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Deferred Work Items

a. Inspection Scope (62707)

The inspector reviewed changes made to the outage work scope. Emphasis was placed on those work items that were removed or deferred from the scope of the cycle 12 refueling outage to determine the effect on safety system performance and consictency with regulatory commitments.

b. Observations and Findings

Changes to the outage work scope are reviewed by the outage review board (ORB). The requested changes to the outage scope are documented on a Task Identification and Change (TIC) form per procedure 3.M.1-46, "Outage Planning." The inspector attended several ORB meetings and verified that TIC items were discussed in sufficient detail and that a quorum of ORB members were present when evaluating emergent work and changes to the outage scope.

The inspector performed a preliminary review of all the TIC items, a total of 48, that were scheduled to be removed or deferred from the outage as of May 31, 1999. Of those, the inspector reviewed 16 of the more safety significant items with the Outage Manager to better understand the issue and the basis for the recommendation. The inspector concluded that the items removed form the outage should not adversely effect equipment performance or overall system reliability.

c. Conclusions

Deferred work items were properly tracked and dispositioned by the outage review board. No work items were removed from the outage scope that would adversely affect safe plant operations.

M3 Maintenance Procedures and Documentation

M3.1 Inservice Inspection Activities

a. Inspection Scope (73753)

The inspectors reviewed the inservice inspection (ISI) activities that were part of Refueling Outage (RFO) 12. The review encompassed witnessing nondestructive examination (NDE) activities in the plant, reviewing the qualifications of NDE personnel, examining NDE procedures and the ISI program manual. Piping welds in sections of the high pressure coolant injection (HPCI) system piping were examined in the field and compared to the piping weld diagrams and the ISI program manual. Additionally, the inspectors assessed BEC Energy's oversight of contractor supplied NDE services and self assessment activities.

b. Observations and Findings

ISI Program Status

Pilgrim was implementing the 1989 edition of Section XI of the American Society for Mechanical Engineers (ASME) code. The unit was in the second period of its third ten-year interval, which began on July 1, 1995. During this outage, Pilgrim began implementing the containment inspection portion of Subsection IWE of the 1992 Addenda of the ASME Code. As required by the code, portions of the containment shell that could be susceptible to degradation had been identified and nondestructively examined.

The inspectors reviewed aspects of the containment inspection plan, and verified that it included known problem areas where degradation (wall thinning) was likely to occur in Mark I containment structures, i.e., at the torus waterline, the drywell sand cushion region, and upper drywell shell. At the time of the inspection, Pilgrim had not found significant degradation.

HPCI System Walkdown and Drawing Review

No deficiencies were identified during the field walkdown of the HPCI system. The HPCI system weld isometric drawings accurately reflected the as-built configuration of the system. Further, the ISI program manual accurately described the location of welds on the HPCI system weld isometric drawings.

Observation of NDE Activities

The inspectors witnessed portions of several NDE activities including an Ultrasonic (UT) examination performed by General Electric personnel on a recirculation system piping weld. The individuals who performed the examination met the training and experience requirements outlined in SNT-TC-1A "Recommended Practice, Personnel Qualification and Certification of Non Destructive Testing."

While observing the UT examinations, the inspectors verified the UT test equipment was calibrated in accordance with industry and BEC Energy standards and personnel were examining the correct area. Further, the inspectors verified that deficiencies uncovered during NDE activities were documented in the Pilgrim corrective action systems.

Oversight and Self Assessment of NDE Activities

During this outage, BEC Energy provided little oversight of vendor supplied NDE activities in the field. Further, over the last two years, comprehensive reviews of the ISI program had not been performed by Pilgrim personnel or an independent third party. Although not an NRC requirement, it is common practice in the industry for utility personnel, as part of an overall quality assurance program, to oversee some aspects of vendor-supplied NDE services in the field and to perform periodic comprehensive reviews of the ISI program. Nevertheless, it did not appear that the absence of such reviews, has degraded the effectiveness of the Pilgrim ISI program.

c. Conclusions

BEC Energy was implementing inservice inspection activities in accordance with their ISI program. NDE personnel were qualified, and adhered to procedures while performing examinations. Deficiencies identified during inspection activities were properly documented. HPCI system weld drawings accurately reflected the location of welds in the plant.

M3.2 Main Transformer Fire

a. Inspection Scope (62707)

The inspector responded to the site for an unusual event on May 18, 1999, involving a fire in the main electrical transformer to assess the licensee's response to the event and evaluate the effect to the plant.

b. Observations and Findings

On May 18, 1999, at 6:32 p.m. a fire occurred at the Pilgrim Station in the main electrical transformer. At the time of the event, the transformer was electrically isolated, with the transformer oil drained to support maintenance and testing activities. The licensee had replaced the "C" phase bushing of the main transformer and was in the process of performing power factor and capacitance testing when smoke was observed coming from the man-way hatch at the top of the unit. Testing was secured and the site fire brigade notified. Shortly thereafter, the licensee requested off-site firefighting assistance and declared an unusual event.

The fire was characterized as "smoldering with no visible flames." Carbon dioxide and a small amount of water was used to suppress the fire. The fire was extinguished at 8:21 p.m., and the Unusual Event terminated at 9:25 p.m. The licensee stationed a continuous fire watch to monitor for the possibility of a reflash. One minor injury occurred to a fire brigade member as a result of a static electrical shock, during use of a carbon dioxide extinguisher.

The inspector responded to the site and monitored the licensee's response to the event. Fire brigade members handled the incident well; the fire was immediately extinguished and there were no serious injuries. The fire had no adverse effect on the plant other than the immediate damage to the transformer. A detailed investigation revealed that the transformer needed to be replaced. The replacement of the transformer resulted in an extension to the original refueling outage schedule. The inspector reviewed the emergency classification guidelines and verified that the licensee properly classified and reported the event.

Problem report PR 99.9231 was initiated to document and evaluate the cause of the fire. The licensee's investigation revealed that the proper gap between the "C" phase bushing and the main output lead was not established during testing. The gap was found to be less than one inch. The exact cause of the fire is still under investigation; however, the licensee postulated that the bushing and the lead were too close to remain electrically isolated resulting in sparking and ignition of the oil soaked insulation material which spread to adjacent equipment.

The testing was performed by contract personnel with oversight provided by a system engineer. The inspector reviewed the test plan and identified that the post work test was part of the maintenance request (MR) and provided little guidance. The MR installed and tested the replacement bushing in accordance with the skill of the craft. There was no specific guidance listing the required gap to be established between the bushing and the main output lead prior to doble testing. Discussions with the Electrical Engineering Department Supervisor revealed that the theoretical gap required between the lead and bushing to prevent spark-over was approximately one inch and the expected gap for testing was to be between 6 - 8 inches. A review of the critique minutes revealed that personnel conducting the test were aware of this requirement.

The inspector determined that marginal procedural guidance and/or human performance errors resulted in the failure to establish the required gap between the bushing and the main output lead resulting in the main transformer fire. The main transformer is a non safety-related component and is outside the scope of 10CFR 50 Appendix B, Quality Assurance Criteria. As a result, no violations of NRC requirements were identified.

c. Conclusions

Response to the main transformer fire by fire brigade members was good; their immediate response prevented any serious damage to the plant. The licensee properly classified the event in accordance with emergency classification guidelines. The failure to establish specific procedural guidance and human performance errors contributed to the cause of the fire.

III. ENGINEERING

E2 Engineering Support of Facilities and Equipment

E2.1 Operability and Engineering Evaluations

a. Inspection Scope

The inspector reviewed a sample of the outstanding operability evaluations (OE) to ensure that guidance information and requirements, such as that included in the plant's technical specifications, Generic Letter 91-18, and the updated final safety analysis report (UFSAR), were being followed. Any applicable compensatory measures taken to assure operability were also included in the review. The sample included risk significant issues associated with motor-operated valves in several systems and other equipment in the emergency diesel generator (EDG), salt service water (SSW), and reactor building closed cooling water (RBCCW) systems. The inspector also reviewed the status of BEC Energy plans to reduce the OE backlog.

b. Observations and Findings

The licensee performs OEs in accordance with Station Procedure No. 1.3.34.5, "Operability Evaluations." The procedure provides a systematic method for evaluating degraded conditions that challenge the operability of safety-related systems, structures, and components (SSC). An OE is usually supported by an engineering evaluation (EE) which is prepared in accordance with Nuclear Engineering Services Group Procedure No. 16.04, "Preparing Engineering Evaluations." At a meeting with the NRC in mid-April

1999, the licensee discussed their plans to resolve about 70 OEs in the next several months. About 5-10 OEs were expected to be open at the completion of RFO12. The inspector's comments concerning specific OEs reviewed are presented below.

<u>OE 98-052 - Excessive Head Loss in the Reactor Building Closed Cooling Water Pump Startup Strainers</u>

This OE was initiated in August 1998 to address a concern that excessive head loss in the RBCCW pump startup strainers may reduce system flow rates below those assumed in the containment heat removal analysis. This concern was identified in Problem Report (PR) 98.9427. Pumps 202B through 202F had startup strainers installed while pump 202A has no strainer. Engineering reviewed the concern of PR 98.9427 and recommended in EE 98-0072 that the RBCCW system should be considered operable based on the following:

- System operability provided an allowance for either pump degradation or increased system resistance (i.e., in this case pump startup strainers) of about 8 PSI. This information was supported by current containment heat removal and the RBCCW system hydraulic analyses, Calculations M-664 and M-770 respectively. No sources of debris were expected in the system to cause a significant increase in strainer head loss from the current value due to normal or post-accident operation.

- Pump net positive suction head (NPSH) requirements would be met since the head tank normally provides about 120 feet of static head contributing to the available NPSH whereas the pump required NPSH was no greater than 27 feet.

Compensatory actions were also recommended in engineering evaluation (EE) 98-0072. Engineering recommended that suction strainer differential pressure should be monitored periodically during normal operation using local suction pressure gage readings to ensure that the strainer pressure drop did not exceed 8 PSI. The licensee indicated that this specific action was not implemented as it was optional. Since this was a recommended and not a required compensatory action, accepted plant practice did not require an Operations Review Committee (ORC) review of EE 98-0072. But the inspector observed that this practice was inconsistent with Nuclear Engineering Services Group (NESG) Procedure No. 16.04 "Preparing Engineering Evaluations," Revision 3, Section 6.0 (4) which stated "engineering evaluations that recommend compensatory actions to ensure operability require ORC review." The licensee recognized this inconsistency with accepted plant practice and stated that NESG Procedure No. 16.04 would be revised to change "recommend" to "require" accordingly. This procedure problem was considered to be a minor violation of NRC requirements and not subject to formal enforcement action. The licensee's actions to correct NESG Procedure No. 16.04 were acceptable.

The licensee closed OE 98-052 on April 26, 1999, on the basis that the startup strainers had been removed from the 5 RBCCW pumps ("B" through "F"). The inspector verified that the strainers were removed and spacer rings were installed to maintain the same flange spacing. The licensee confirmed that the condition of the startup strainers upon removal evidenced nothing unusual that would have invalidated any prior assumptions and conclusions made in EE 98-0072. Maintenance request information was appropriately noted on the OE 98-052 closeout form to indicate suction strainer removal with one exception. The inspector noted that operations personnel inadvertently omitted documenting maintenance request 19801964 on the record copy of the OE 98-052 closeout form to substantiate that the startup strainer was removed from the "C" pump. The system engineer verified that maintenance request 19801964 did accomplish removal of the "C" pump startup strainer.

The inspector concluded that the closure of OE 98-052 was acceptable.

<u>OE 98-057 - RBCCW System Discrepancies Impacting Loss of Inventory Procedure</u>

After the review of an industry event related to the loss of inventory from safety related closed loop cooling water systems, the licensee issued this OE in September 1998. The licensee identified two discrepancies that required resolution:

- The chemical addition tanks were designated as non safety-related on the master list of plant equipment and there were insufficient controls in Station Procedure 7.1.92, "Addition of Chemicals to the RBCCW, TBCCW, and Station Heating Systems," to ensure they were in service for the minimum time required.

- The mechanical seals on the RBCCW pumps were also designated as non safety-related on the master list of plant equipment, and insufficient inventory existed in the head tank to maintain RBCCW system operability during a postulated catastrophic failure of one or more pump seals.

Resolution of the first discrepancy was accomplished by revising Station Procedure 7.1.92 to valve in the chemical addition tanks for 15 minutes when adding chemicals. The inspector verified that the procedure was changed to isolate the chemical addition tanks after this 15-minute period or if RBCCW system leakage might be encountered. The inspector considered this discrepancy to be resolved.

The licensee evaluated the second discrepancy in EE 98-0075 and concluded that the currently installed seals were operable based on their in-service performance (i.e., excellent service and reliability since 1992) and the accessibility of the components for visual inspection and monitoring. For example, the most significant examination for a mechanical seal application is the in-service leak test at normal operating pressure. The pressure boundary parts of the seal are normally exposed to the system operating pressure. Operator tours have been sufficient for detecting unacceptable leakage. The inspector considered this justification to be acceptable. The licensee intends to replace the RBCCW pump mechanical seals with safety related material later in 1999 which will enable closure of this OE.

OE 98-058 - Undedicated Commercial Grade Material Installed in Safety Related Salt Service Water System

This OE was issued in September 1998 when the licensee determined that some metallic parts (control rod plates, control rods, compression sleeves, nuts, and washer plates) of six expansion joints were received as commercial grade material and had not been properly dedicated for safety related use prior to installation into the salt service water (SSW) system. The licensee considered the expansion joints to be operable based on EE 98-042. Discussion with the expansion joint supplier indicated that the metallic parts were manufactured from ASTM A-36 carbon steel material. The licensee determined that the maximum pipe movements expected in the affected SSW piping were less than the range of the expansion joints (i.e., gaps are provided on the control rods to accommodate a range of allowable motion). Therefore, the licensee expected the loading on the expansion joint metallic parts to be within the limits of the A-36 specification and took actions to confirm that the material was consistent with A-36 composition and properties.

The inspector verified that the licensee completed appropriate material testing for the in-plant material. Mass spectrometry tests were performed at several affected expansion joints in the SSW pump house. The test results indicated a carbon content that matched to A-36 material. Hardness tests were performed on a spare expansion joint (procured similar to the installed expansion joints) located in the warehouse and the mechanical properties compared favorably to A-36 material.

The inspector noted that modification FRN98-01-37 was scheduled to be implemented during RFO12 to enable close out of OE 98-058 by installing expansion joints with fully qualified material. The inspector concluded that the licensee's actions concerning OE 98-058 were acceptable.

OE 98-013 - Emergency Diesel Generator Ambient Air Temperature Low

This OE was issued to address the concern regarding overall engine temperature while the emergency diesel generator (EDG) is in a standby status and the effect that this temperature has on the EDG ability to start and accept initial load. OE 98-013 was issued in March 1998 and was supported by EE 97-066, Rev. 2. Technical justification was presented to support EDG operability provided that:

- Temperature (Outside) > (-) 20°F, and Temperature (Room) $\geq$ 40°F

The licensee's justification was technically sound and well supported by the EDG vendor information.

The licensee intends to implement a plant modification (documentation only), Plant Design Change (PDC) No. 99-09, "Decrease of the EDG Building Low Temperature Design Limit," to permanently change the EDG room design temperature (lower limit) from 60°F to 40°F. The licensee indicated that this modification probably would not be completed until after restart from RFO 12. The inspector provided a comment which challenged the comprehensiveness of the scope of PDC 99-09 and its associated

Calculation M893. It was not apparent that structural considerations would be reviewed regarding the 20°F EDG room design temperature decrease and the resultant impact on existing piping stress analysis, EDG silencer supports and movement, and possible impact of low temperature/brittle fracture on the compressed air receiver pressure vessels. The licensee agreed to consider these considerations in the final development of PDC 99-09. The inspector considered this comment to be a weakness in the engineering work completed so far in support of PDC 99-09.

MOV Operability Evaluations

The inspector reviewed eight operability evaluations related to motor-operated valves (MOVs). While design margins were reduced in each case, the MOVs remained capable of performing their design-basis functions either when some of the conservatism inherent in the design calculations was removed or the results of dynamic tests were credited. The evaluations and corrective actions were consistent with the licensee's commitments made in response to Generic Letter 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves." The operability evaluations are summarized below:

- OE 97-09: The minimum motor control center (MCC) voltages of high pressure coolant injection (HPCI) torus suction valves MO2301-35 and MO2301-36 were calculated incorrectly using generic locked rotor currents. However, using motor-specific locked rotor current values, the motors still develop adequate output torque for the valves to perform their safety functions under degraded voltage conditions.

- OE 97-10: New, slightly higher calculated peak accident drywell ambient temperature resulted in a small decrease in the minimum available motor output torque of containment isolation valves MO1301-16, MO1001-50, and MO220-1. Valve operability was based on the fact that (1) the MOVs are called upon to operate prior to reaching peak design temperature, (2) motor winding heatup significantly lags the ambient temperature increase, (3) the methodology used to derate the motors discounts the increased motor terminal voltage due to higher winding temperature, and (4) the entire motor cable lengths are not exposed to peak accident temperature.

- OE 97-13: New undervoltage calculations reduced the available motor output torques of six direct current MOVs, raising the potential that available torque would be insufficient to trip the torque switches. However, valve testing showed that sufficient torque would exist to actuate the switches. Also, the licensee demonstrated that low pressure coolant injection (LPCI) valve MO1001-29A still had adequate design margin after increasing the design valve factor from 0.5 to 0.62.

- OE 97-14: Under high design ambient temperature conditions, reactor core isolation cooling steam admission valve MO1301-61 may not develop enough torque to trip the torque switch. The licensee calculated that sufficient motor output torque existed by reducing generic motor output curve uncertainty from 15% to 5% on the basis of motor-specific tests.

- OE 97-15: The valve factor of LPCI injection valve MO1001-29B was increased due to reevaluation of dynamic test results. While reduced, the valve's design margin remained adequate.

- OE 97-17: Reactor recirculation pump discharge valves MO220-5A/B had a negative margin against the differential pressure (200 psid) assumed to occur during a pump seal failure. The licensee considered the differential pressure provided in the General Electric Company design specification to be overly conservative. Also, the plant accident analysis bounds any seal leakage that would persist if the valves fail to close. Thus, isolation of the recirculation pumps is not a safety-related function.

- OE 98-87: HPCI steam supply valve MO2301-3 did not indicate fully closed during a dynamic test due to an increase in stem-to-stem nut friction at flow isolation and torque switch trip. Also, the valve experienced a sustained torque increase in the hammer-blow region of the opening stroke. However, the valve does not have a safety function to close under dynamic conditions and full flow cutoff was achieved during the test. During the opening stroke, no corresponding increase in thrust was measured in the hammer-blow region, indicating that the motor was relieving the load stored in the actuator's compensating spring pack. The valve's design torque margin (about 20%) in the open direction was acceptable.

- OE 98-79: Seven valves showed reduced or negative design margins when thrust requirements were re-calculated using the Electric Power Research Institute's performance prediction methodology (PPM). BECo demonstrated that the valves remained operable by removing some design conservatism regarding motor output capability, stem friction coefficients and packing loads, and/or design fluid conditions, or by taking credit for dynamic test results. BECo is evaluating potential design changes to restore full design-basis capability to these valves.

<u>OE Backlog Reduction Plans</u>

The inspector met with engineering and operations personnel who indicated that the OE backlog reduction plans, which projected about 5-10 open OEs at the end of RFO 12, were still on schedule. The inspector noted that at least two additional OEs (plus the five identified during a meeting with the NRC in Region I on April 15, 1999) have been identified as very likely to remain open after restart. The first one, OE 98-013, "EDG Low Ambient Air Temperature," was discussed above. A second OE could likely develop and remain open to address a core spray pump NPSH problem associated with Problem Report 99.9195 which was just identified on May 12, 1999.

Notwithstanding these observations, the licensee appears to be generally on track to close out the majority of OEs during RFO 12 and expects to have 5-10 OEs open prior to restart. Operations and engineering meet at least monthly to review outstanding OEs and a quarterly report is issued to assure proper control of the OE backlog.

c. Conclusions

The inspector sampled about 10% of the 70 plus outstanding OEs. No major safety concerns were noted. Some minor problems were observed. These included attention-to-detail problems pertaining to the procedures governing operability and engineering evaluations. Also, the preliminary engineering work supporting PDC 99-09 was not comprehensive in that structural considerations were not being reviewed regarding the 20°F EDG room design temperature decrease and the resultant impact on the piping stress analysis, the EDG silencer supports, and the compressed air receivers. The licensee was taking appropriate corrective actions to resolve these problems.

BECo appeared to be ontrack in reducing the number of open OEs. At the end of RFO 12 BECo expected to have 5-10 open OEs, which would be comparable to that discussed in a meeting with the NRC in Region I on April 15, 1999. A process was in place to control the OE backlog and BECo recognized the need to monitor this process to achieve and maintain backlog goals.

E8 Miscellaneous Engineering Issues

E8.1 Y2K Compliance

The staff conducted an abbreviated review of Y2K activities and documentation using Temporary Instruction (TI) 2515/141, "Review of Year 2000 (Y2K) Readiness of Computer Systems at Nuclear Power Plants." The review addressed aspects of Y2K management planning, documentation, implementation planning, initial assessment, detailed assessment, remediation activities, Y2K testing and validation, notification activities, and contingency planning. The reviewers used NEI/NUSMG 97-07, "Nuclear Utility Year 2000 Readiness," and NEI/NUSMG 98-07, "Nuclear Utility Year 2000 Readiness Contingency Planning," as the primary references for this review.

The results of this review will be combined with the results of other reviews in a summary report to be issued by July 31, 1999.

E8.2 (Closed) LER 50-293/97-17-01: SSW Temperatures Greater Than Design

This LER supplement documents the need for additional net positive suction head (NPSH) required for ECCS pumps which was greater than the licensing basis values. LER 97-17 was originally reviewed and closed in NRC Inspection Report No. 50-293/98-

09. Subsequently, the licensee submitted a request for a license change in letter no. 2.99.001, dated January 21, 1999. This request was under review by NRR during this inspection period. The need for additional over-pressure was due to a new debris analysis evaluation of the ECCS suction strainers located in the torus. The inspector conducted an onsite review of this LER supplement and verified that the corrective actions are being tracked by the licensee's corrective action program. The inspector determined that this LER supplement met the intent 10 CFR 50.73. No problems were identified. This LER supplement is **closed.**

E8.3 (Closed) LER 50-293/98-21: Inadequate Fuel Supply for Emergency Diesel Generators (EDGs)

This LER documents that the technical specification minimum fuel requirement of 19,800 gallons for each EDG is insufficient to support the electrical loads specified in the Updated Final Safety Analysis Report (UFSAR). The UFSAR specifies sufficient fuel be available to support EDG operation for seven days. The licensee discovered a more limiting fuel consumption case than had been included in the original design calculations, indicating that assumptions used were non-conservative and inconsistent with those in the UFSAR. Based on this case, the available EDG fuel could support operation of the diesel for only four days at maximum loading. However, the licensee still considered the EDGs operable based on how the loads would be operated using the Pilgrim emergency operating procedures. Problem report PR98.9462 was written to document this condition and to initiate corrective actions.

As corrective action, the licensee issued a standing order to notify the technical support center to develop a fuel utilization strategy in the event of a LOOP coincident with a LOCA. This would ensure that sufficient diesel fuel would be available to supply the EDGs for a seven day period. Also, the licensee submitted a technical specification amendment (to allow crediting the station blackout diesel fuel oil supply) to the NRC for review in May 1999.

The inspector conducted an onsite review of the LER and verified that an operations department standing order was issued, and that a technical specification amendment had been submitted to the NRC for review. The inspector questioned the licensee regarding whether preliminary calculations had been performed that demonstrate a fuel utilization strategy would result in an adequate diesel fuel supply for a seven day period and whether any specific guidance was provided to operators on what non-essential loads could be shed during an accident. In response to this question, the licensee indicated that more specific guidance would be made available to operators.

The inadequate implementation of the requirement to have a seven day fuel supply is a violation of design control requirements contained in 10CFR 50, Appendix B, Criterion III. This item was licensee-identified during its review of calculation adequacy as part of the design basis document initiative. The immediate and long term corrective actions were comprehensive and either completed or appropriately scheduled for completion in a reasonable time. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC

Enforcement Policy. This violation is in the licensee's corrective action program as PR 98.9462). (**NCV 50-293/99-03-03**). This LER is **closed**.

E8.4 (Closed) LER 50-293/98-23: Incorrect Wiring Modifications Affected Reactor Building Closed Cooling Water (RBCCW) Train "B" Alternate Shutdown Panel

This LER documented that the RBCCW train "B" alternate shutdown panel was inoperable since 1992 due to a wiring error during the implementation of a modification. The train "A" panel was correctly implemented and thus not affected. This condition was identified by the licensee during troubleshooting of an indicating light not illuminated (blown fuse) on the RBCCW train "B" alternate shutdown panel. Because of the incorrect wiring the alternate fuse would not be switched into the alternate shutdown circuit during switching from the remote to local position. Problem report 98.9515 was written to document this condition, and a drawing change was issued and the licensee corrected the panel wiring to restore the system to an operable status. The licensee's extent review did not identify any similar problems.

The inspector conducted an onsite review of the LER and determined the corrective actions were appropriate. The inspector verified that a drawing change was made and that the wiring error was corrected. The incorrect implementation of an engineering modification was considered a violation of NRC design control requirements. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PR 98.9515 (**NCV 50-293/99-03-04**). This LER is **closed**.

E8.5 (Closed) LER 50-293/98-28: Control Room High Efficiency Air Filtration (CRHEAF) System Relative Humidity Switches Inoperable

This LER documented that the CRHEAF system relative humidity switches were inoperable. As part of the design basis information program the licensee performed a set point calculation of the CRHEAF system. This revealed that the set point for statistical uncertainty was 25 percent. Applying this factor to recently performed and past surveillances would cause the relative humidity to exceed the technical specification value. The cause of the statistical uncertainty (instrument drift) was attributed to degradation of the nylon filaments that are part of the humidity switch. Problem report 98.9621 was written to document this condition. As an immediate corrective action, the licensee declared the CRHEAF system inoperable and performed a temporary modification that results in heating coils to energize whenever the system is in placed in operation.

The inspector conducted an onsite review of the LER and determined that the corrective actions were appropriate. The inspector verified that the licensee properly implemented technical specification requirements and that the temporary modification was properly installed. The failure of the CRHEAF system humidity switches to maintain the relative humidity of the system below 70 percent is a violation of TS 3.7.B.2. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PR 98.9621 (**NCV 50-293/99-03-05**). This LER is **closed**.

E8.6 (Closed) LER 50-293/98-29: Intake Structure Indoor Air temperature Less Than Design

This LER documents that the air temperature inside the intake structure went below the UFSAR specified design value of 60°F. Problem report 98.9644 was written to document and evaluate this condition. This issue was previously documented and reviewed in NRC Inspection Report 50-293/98-11, section O1.1. No violations of NRC requirements were identified. This LER is **closed**.

IV. PLANT SUPPORT

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Radiological Controls for Refuel Outage No. 12 (RFO12)

a. Inspection Scope (83750)

A review was performed of radiological controls implemented for Pilgrim's cycle 12 refuel outage. Information was gathered through tours of the plant; discussions with health physics technicians and supervisors; evaluations of radiological boundaries; a review of high radiation area controls; a review of the radiologically controlled area portal monitor log; through reviews of radiation dose goals; and a review of radiological control improvements implemented for drywell work.

b. Observations and Findings

The radiological controls organization maintained close oversight of plant work as evidenced by the presence of knowledgeable health physics technicians stationed at major plant work areas including the radiologically controlled area red line, the drywell, reactor building, fuel floor, and condenser bay.

Tours through the plant showed that radiological control boundaries were well defined and clearly posted. Controls for high radiation area access included use of radiation work permits (RWPs); use of alarming dosimetry; radiological postings; required use of locked access controls or flashing lights for areas that could result in an individual receiving a dose equivalent in excess of 1000 mrem per hour at 30 centimeters; and increased health physics oversight and monitoring. Tours of the plant confirmed that high radiation and locked high radiation areas were appropriately posted and doors that were required to be locked were found locked or appropriately controlled by health physics staff.

Direct observations of drywell work indicated that appropriate radiological controls were implemented including use of radiation work permits, radiological postings, constant health physics oversight, health physics briefings, appropriate evaluations of working conditions including radiological surveys, and use of alarming dosimetry.

Direct observations of controls implemented for the removal of a potentially highly irradiated 3/4 inch cap screw from control rod drive tube cell 02-23 in the reactor cavity indicated that appropriate radiological surveys were taken to ensure that removal of the cap screw from the water did not present a radiation hazard and appropriate controls were taken to prevent the spread of contamination.

Direct observations of work performed at the condenser bay indicated that appropriate controls were taken to protect personnel from contamination including use of radiation work permits, radiological postings, and use of protective clothing.

Radiation Dose Goals

Radiation dose goals were established and tracked for major outage work. The station radiation dose goal for RFO12 was set at 310 person-rem and included 28 person-rem for minor electrical and mechanical maintenance, 27 person-rem for main steam isolation valve work (MSIV), 17 person-rem for reactor pressure vessel nozzle work, 16 person-rem for control rod drive replacement, 16 person-rem for motor operated valve work, 12 person-rem for drywell shielding, and 9 person rem for torus diving and desludging activities. Dose estimates were used as the basis for radiological planning, and performance versus dose-goals were routinely tracked and frequently communicated to plant staff.

Drywell Improvements

Drywell work presented a significant challenge to the radiological controls staff due to elevated dose rates on reactor water re-circulation piping, core spay piping, reactor water cleanup piping, and residual heat removal (RHR) piping. Approximately 68 percent of projected station dose (212 person-rem) was estimated to be received performing drywell work. Radiological survey results showed that typical dose rates on reactor vessel nozzles ranged from 1000 - 2000 mrem per hour and the majority of general area dose rates in the drywell ranged from 40 - 110 mrem per hour. The drywell radiological controls coordinator stated that in order to minimize drywell dose, multiple work efficiency and dose reduction initiatives were implemented including the assignment of a drywell radiological controls coordinator in advance of the outage, development of a drywell improvement plan, installation of permanent shielding, installation of video cameras for monitoring of key work areas; placement of a tool crib at the drywell entrance; use of cord stands to keep electrical cords and hoses off of walkways; use of scaffolding staging racks to minimize clutter; increased use of temporary lighting; use of a motorized hoist, and development of a Drywell Field Guide for briefings. The drywell coordinator stated that accumulated personnel doses for drywell work were below projected estimates.

Detectable Shoe Contaminations

A review of a portal monitor log located at the radiologically controlled area (RCA) egress point (red line) indicated that during a 24 hour period from the morning of May 18, 1999, to May 19, 1999, there were approximately 175 occurrences in which some level of contamination was detected on personnel shoes. The majority of shoe contaminations were of very low activity with only ten exceeding the limit for documenting a personal contamination report. None of the detected contaminations resulted in any measurable personnel exposure. The radiation protection manager stated that additional decontamination personnel would be assigned to wet-mop areas adjacent to contaminated area boundaries, that additional sticky pads would be placed in the plant to minimize the spread of contamination, and a review of ventilation flow paths would be initiated. Problem Report 99.1507 was subsequently generated to resolve the cause for the condition.

RHR Shut Down Cooling Crud Burst

Licensee staff reported that "crud bursts" occurred when the A-loop and B-loop of residual heat removal (RHR) shut down cooling systems were placed in-service. Corrosion products including iron-59 and cobalt-60 were released into the reactor cavity, the fuel pool cooling system, and the A and B-loops of the RHR system. This had the immediate effect of clouding reactor cavity water which resulted in the temporary suspension of in-vessel work and increasing radiation dose rates in the fuel pool skimmer corridor and the RHR A and B-Quads. The radiation protection manager stated that due to the limited scope of outage work planned in affected areas, the increases in dose rates were not expected to significantly increase outage dose. The exact reasons for the crud burst were not immediately known. Preliminary findings indicated that the crud was a result of deposits in the dead legs of the RHR system from a recent chemical decontamination. Details of the event were placed on the nuclear network, other plants were contacted to evaluate similar occurrences, and a review of the impact of the crud burst on plant systems and components was initiated.

c. Conclusions

Radiological controls were effectively implemented for Pilgrim's twelfth refuel outage (RFO12) as evidenced by close health physics oversight of work and improvements in radiological controls for drywell work including assignment of a drywell radiological controls coordinator, installation of permanent shielding, and use of video monitoring.

R1.2 Drywell Upper Level Access Controls

a. Inspection Scope (83750)

The potential exists for dose rates to increase in the upper elevations of the drywell if irradiated fuel, irradiated core components, or equipment with the potential for elevated dose rates such as underwater vacuums are dropped, placed on, or come in close physical proximity to the cavity/drywell bulkhead. A review was performed of radiological controls implemented to protect drywell workers during movement of irradiated fuel, irradiated core components, or equipment with elevated dose rates. Information was gathered through interviews with cognizant personnel, tours through the drywell and fuel floor, and a review of the following documents:

- Procedure No. 6.1-009, "Radiological Controls for Handling Highly Activated Components and Underwater Equipment;"
- Procedure No. 4.3, "Fuel Handling;" and
- RFO-12 Drywell Field Guide.

b. Observations and Findings

Formal radiological controls for the movement of irradiated fuel were included in Operations procedure PNPS 4.3, "Fuel Handling," and required the use of a bulkhead shield (cattle shoot) for the movement of fuel between the cavity and the fuel pool and stated that "Radiation Protection shall post access above 63' elevation in the drywell if fuel is handled." However, only informal programmatic controls were in-place to ensure that drywell workers did not receive an unplanned exposure due to the movement of irradiated core components or equipment with the potential for elevated dose rates such as underwater vacuums. Two examples were identified by the inspector which had the potential for increasing dose rates in the upper elevations of the drywell:

- During refuel outage No. 11 (RFO11) the core shroud tie-rod was moved from the reactor cavity over the drywell bulkhead to the equipment pit. If this component had been placed or accidentally dropped on the cavity/drywell bulkhead dose rates could have increased in the upper elevation of the drywell.

- Three operating underwater vacuums used to filter reactor cavity water were observed to have been placed directly on the reactor cavity/drywell bulkhead. Placement of an operating underwater vacuum directly on the cavity/Drywell bulkhead had the potential to increase dose rates in the upper elevations of the drywell.

The radiation protection manager (RPM) acknowledged the opportunity for improvement and took the following actions to improve program controls: 1) four remote radiation monitors were placed in the upper elevation of the drywell to allow the health physics staff to remotely monitor dose rates in the upper elevations of the drywell; 2) health physics technicians assigned to the fuel floor and drywell were briefed on the potential for increasing dose rates in the upper drywell during movement of components and equipment with elevated dose rates; 3) advice on procedural controls was solicited from other sites, and 4) an action item was initiated to evaluate and implement formal program controls.

c. Conclusion

An opportunity for improving radiological controls for access to upper drywell elevations during movement of irradiated core components was identified and licensee staff responded quickly to improve program controls.

R7 Quality Assurance in RWP&C Activities

a. Inspection Scope (83750)

A review was performed of the use of the problem reporting system for the identification and resolution of radiological control deficiencies. Information was gathered through selected reviews of problem reports and through discussions with cognizant personnel.

b. Observations and Findings

Deficiencies and opportunities for improvement were placed into the problem reporting system for evaluation and resolution. A selected review showed that appropriate evaluations were performed and timely corrective and preventative actions were implemented for identified deficiencies.

c. Conclusions

The problem reporting system was effectively used to identify, evaluate, and resolve radiological control deficiencies.

S1 Conduct of Security and Safeguards Activities (81700)

a. Inspection Scope (81700)

Determine whether the conduct of security and safeguards activities met the licensee's commitments in the NRC-approved security plan (the Plan) and NRC regulatory requirements. The security program was inspected during the period of May 10-12, 1999. Area inspected: access authorization.

b. Observations and Findings

Access Authorization. A review of the access authorization (AA) program was conducted to verify that program implementation was in accordance with applicable regulatory requirements and Plan commitments. The review included an evaluation of the effectiveness of the AA procedures, as implemented, and an examination of AA records for several individuals. The AA program, as implemented, provided assurance that persons granted unescorted access did not constitute an unreasonable risk to the health and safety of the public. Additionally, a review of access denial records and applicable procedures revealed that appropriate actions were taken when individuals were denied access or had their access terminated. Those actions included the availability of a formalized process that allowed the individuals the right to appeal the licensee's decision.

c. Conclusions

The licensee was conducting its security and safeguards activities in a manner that protected public health and safety and that this portion of the program, as implemented, met the licensee's commitments and NRC requirements.

S7 Quality Assurance (QA) in Security and Safeguards Activities (81700)

a. Inspection Scope

The areas inspected included audits, problem analyses, corrective actions, and effectiveness of management controls.

b. Observations and Findings

Audits. A review was conducted of the most recent physical security program audit and the Fitness for Duty (FFD) audit. Both audits were found to have been conducted in accordance with the plan and FFD rule. The audits were thorough and in depth, and the audit teams included independent technical specialists. Findings from the audits were not indicative of program weakness and implementation of the corrective actions for the findings were generally to effect program enhancements.

Problem Analyses. A review of data derived from the security department's self-assessment program indicated that potential weaknesses were being tracked, and trended.

Corrective Actions. A review was conducted of the corrective actions implemented by the licensee in response to both the QA audits and the self-assessment program. All corrective actions had been implemented and the corrective actions were effective.

Effectiveness of Management Controls. The licensee has programs in place for identifying, analyzing and resolving problems. The programs included the performance of annual QA audits, a departmental self-assessment program, and the use of industry data, such as violations of regulatory requirements identified by NRC at other facilities, as criterion for self-assessment.

c. Conclusions

Audits of the security program were comprehensive in scope and depth, and findings were reported to the appropriate level of management. The self-assessment program was effectively implemented to identify and resolve potential weaknesses.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

The inspector met with licensee representatives at the conclusion of the inspection on June 29, 1999. At that time, the purpose and scope of the inspection were reviewed, and the preliminary findings were presented. The licensee acknowledged the preliminary inspection findings.

ATTACHMENT 1

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observation
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 81700:	Physical Security Program for Power Reactors
IP 82301:	Evaluation of Exercises for Power Reactors
IP 83750:	Occupational Radiation Exposure
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901:	Followup - Operations
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors
TI 2515/141	Y2K Readiness Review

ITEMS OPENED, CLOSED, AND UPDATED

Closed

LER 50-293/97-17-01	SSW Temperatures Greater Than Design
LER 50-293/98-21	Inadequate Fuel Supply for Emergency Diesel Generators (EDGs)
LER 50-293/98-23	Incorrect Wiring Modifications Affected Reactor Building Closed Cooling Water (RBCCW) Train "B" Alternate Shutdown Panel (
LER 50-293/98-28	Control Room High Efficiency Air Filtration (CRHEAF) System Relative Humidity Switches Inoperable
LER 50-293/98-29	Intake Structure Indoor Air temperature Less Than Design
NCV 50-293/99-03-01	Tagging error
NCV 50-293/99-03-02	The failure to position valve MO-1001-28B open per step 3(c) of procedure 8.M.3-1
NCV 50-29/99-03-03	Inadequate Fuel Supply for Emergency Diesel Generators (EDGs)
NCV 50-293/99-03-04	Incorrect Wiring Modifications Affected Reactor Building Closed Cooling Water (RBCCW) Train "B" Alternate Shutdown Panel
NCV 50-293/99-03-05	Control Room High Efficiency Air Filtration (CRHEAF) System Relative Humidity Switches Inoperable

LIST OF ACRONYMS USED

CAS	Central Alarm Station
CCTV	closed circuit television
CFR	Code of Federal Regulations
CRHEAF	Control Room High Efficiency Air Filtration
DRP	Division of Reactor Projects
EDG	Emergency Diesel Generator
FSAR	Final Safety Analysis Report
IFI	Inspection Follow-Up Item
IR	Inspection Report
LCO	Limiting Condition of Operation
LER	Licensee Event Report
mrem	millirem
MR	Maintenance Request
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NOV	Notice of Violation
NPO	Nuclear Plant Operator
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
PA	protected area
PDR	Public Document Room
PNPS	Pilgrim Nuclear Power Station
PR	Problem Report
PWT	Post Work Test
QA	quality assurance
RCA	Radiologically Controlled Areas
RFO	Refueling Outage
RHR	residual heat removal
RP	Radiological Protection
RPM	radiation protection manager
RWP	radiation work permit
SAS	Secondary Alarm Station
SBLC	Standby Liquid Control
SBO	Station Blackout
SFM	security force member
T&Q	training and qualification
the Plan	NRC-approved physical security plan
UFSAR	Updated Final Safety Analysis Report
VIO	Violation